GREY WOLF EXPLORATION INC.

ANNUAL INFORMATION FORM
For the year ended December 31, 2000

March 14, 2001

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GLOSSARY OF ABBREVIATIONS AND TERMS

In this Annual Information Form, the following abbreviations and terms have the following meanings:

Crude Oil and Natural Gas Liquids (NGLs):	bbl	-	barrel
	bbls/d	-	barrels per day
	mbbls	-	1,000 barrels
	mmbbls	-	1,000,000 barrels
Natural Gas:	mcf	-	1,000 cubic feet
	mmcf	-	1,000,000 cubic feet
	bcf	-	1,000,000,000 cubic feet
	mcf/d	-	1,000 cubic feet per day
	mmcf/d	-	1,000,000 cubic feet per day

ARTC	-	Alberta Royalty Tax Credit
BOE	-	Barrels of oil equivalent; 10 mcf of natural gas equals 1 bbl of oil
BOE/d	-	Barrels of oil equivalent per day
Netbacks	-	Oil and gas production revenues less royalties and operating expenses.
mmbtu	-	Million British Thermal Units

CONVERSION

The following table sets forth certain standard conversions from Standard Imperial units to the International System of units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metre ("m^3")	28.174
Bbl	Cubic metre ("m^3")	0.1589
Feet	Metre	3.3
Mile	Kilometre	1.6

INCORPORATION

On December 31, 1993, Cascade Oil & Gas Ltd. amalgamated with Index Petroleums Ltd. under the provisions of the *Business Corporations Act* (Alberta) to form Cascade Oil & Gas Ltd. On June 11, 1998, Cascade Oil & Gas Ltd. changed its name to Grey Wolf Exploration Inc. (hereinafter "Grey Wolf" or the "Corporation"). In June 1999, the Corporation filed Articles of Amendment and a one for ten consolidation of common shares was completed. All references in this Annual Information Form ("AIF") to common shares of Grey Wolf reflect this consolidation, unless otherwise specified.

The head and principal office, as well as the registered office, of Grey Wolf is located at 1600, 255 – 5th Avenue S.W., Calgary, Alberta, T2P 3G6.

GENERAL DEVELOPMENT OF THE BUSINESS

The Corporation is a natural gas company which focuses its efforts on exploring for, developing, acquiring and producing petroleum and natural gas in western Canada and the Northwest Territories. Natural gas in central and northern Alberta accounts for over 90% of the Corporation's reserves and production.

The Corporation operates and manages a working interest in all of its major properties. Investments in producing, development and exploratory petroleum and natural gas properties is done after consideration of such factors as strategic compatibility with core areas and potential for future growth through the application of geoscience and/or engineering expertise.

In late 1995, a majority of the Corporation's shareholders approved the sale of 40,910,000 common shares, representing two-thirds (2/3) of the total outstanding shares issued, at $0.10 per share for gross cash proceeds of $4,091,000 to Grey Wolf Exploration Ltd. ("Grey Wolf Ltd."). Grey Wolf Ltd. was a private corporation controlled 78% by Abraxas Petroleum Corporation ("Abraxas"). This transaction gave Abraxas effective ownership of approximately 52% of the common shares of the Corporation. The sale and purchase of shares took effect on January 4, 1996.

In June, 1997, the Corporation sold substantially all of its Saskatchewan petroleum and natural gas properties for cash proceeds of $1.4 million. The sold Saskatchewan properties accounted for the majority of the Corporation's petroleum and natural gas operations at that time.

As part of the Corporation's search for opportunities to invest in oil and gas operations in the western Canadian sedimentary basin, Grey Wolf participated with Abraxas in evaluating the purchase of Canadian Gas Gathering Systems Inc. ("CGGS"). In the fourth quarter of 1996, Canadian Abraxas Petroleum Limited ("Canaxas"), a wholly-owned subsidiary of Abraxas, acquired the shares of CGGS for $130.5 million, including $13.7 million of working capital. The Corporation signed a contract to manage Canaxas and exercised an option to acquire 10% of the Canaxas CGGS interests, effective July 1, 1997, for a total consideration of $9.3 million consisting of $8.5 million in cash and the issuance of 2,051,282 common shares.

On September 1, 1997, the Corporation acquired all of the common shares of Pennant Petroleum Ltd. ("Pennant") in exchange for the issuance of 7,585,000 common shares.

In October 1997, the Corporation acquired an 8.27% interest in certain oil and gas producing properties sold by Pacalta Resources Ltd. ("Pacalta"). Total consideration for the purchase was $2.13 million in exchange for $171.6 thousand in cash and the issuance to Pacalta of four million special warrants which were subsequently exchanged for an equal number of common shares of the Corporation.

On November 4, 1997, the Corporation acquired 100% of the common shares of Grey Wolf Ltd. in exchange for the issuance by the Corporation of 42,741,053 common shares (preconsolidation) to the Grey Wolf Ltd. shareholders and the cancellation of 40,910,000 common shares (preconsolidation) held by Grey Wolf Ltd. Grey Wolf Ltd. was wound up into the Corporation immediately after the acquisition. Grey Wolf Ltd. was previously the majority shareholder of the Corporation and its assets consisted of 40,910,000 common shares (preconsolidation) and some minor oil and gas property interests which generated nominal revenues and earnings. This reorganization transaction resulted in the share ownership in the Corporation previously held by Grey Wolf Ltd. being passed to the Grey Wolf Ltd. shareholders.

In August 1998, the Corporation successfully completed a prospectus offering of 50 million common shares (preconsolidation) for gross proceeds of $16 million. Concurrent with the closing of this financing, the Corporation acquired from Canaxas the 91.73% of certain oil and gas producing properties sold by Pacalta to Canaxas in October, 1997, for a total cash consideration, after adjustments, of $21.6 million.

In January 1999, the Corporation acquired, effective July 1, 1999, a 25% interest in certain undeveloped lands and proprietary seismic data owned by New Cache Petroleums Ltd. ("New Cache") for a total cash consideration of $3.4 million. In addition, the Corporation entered into a farmout agreement with New Cache whereby Grey Wolf will earn additional interests in the acquired lands by paying a share of New Cache's seismic and drilling costs. Under this farmout agreement, Grey Wolf agreed to spend a minimum of six million dollars on the acquired lands over three years.

On May 20, 1999, the Corporation's shareholders approved the consolidation of the share capital of the Corporation on the basis of one common share for each ten common shares outstanding.

The Corporation has experienced management, technical and support staff in the operations, exploitation, exploration, land, marketing, financial management and administrative areas. At December 31, 2000, Grey Wolf had 32 (1999 – 27) full-time employees in its Calgary head office and 10 (1999 – 14) full-time employees in field locations.

BUSINESS OF THE CORPORATION

Principal Properties

The following is a description of the Corporation's principal properties and natural gas facilities, all of which are located in the provinces of Alberta and British Columbia, and the Northwest Territories.

Caroline, Alberta

Through a property swap transaction, Grey Wolf acquired a thirty party's interest in the Sundre gas plant, 58 sections of land and associated wells in November 2000. After the acquisition, Grey Wolf had an interest in 45,939 acres (19,589 net) of land. Grey Wolf operates the majority of the area's production and at year-end had an interest in a total of 38 wells (13.6 wells net); its average interest increasing in 2000 from 17.6% to 43% by virtue of the acquisition. Of the 38 wells, 32 (12.1 net) are producing and 6

(1.5 net) are non-producing. Gross natural gas production from the wells averaged 8,400 mcf/d in 2000 and Grey Wolf's share was 1,272 mcf/d. Grey Wolf's share of crude oil and NGL sales was 62 bbls/d.

The Sundre gas plant has a licensed capacity to handle 20 mmcf/d of gas. The acquisition increased Grey Wolf's working interest in the plant from 37.3% to 64% and net ownership capacity from 7.5 mmcf/d to 12.8 mmcf/d.

In 2000, Grey Wolf participated in drilling five wells (2.17 wells net), of which four (1.67 wells net) were successful in various zones. In addition, there were three successful re-completions (1.52 net). Projects planned for 2001 currently include drilling six wells, recompleting five wells, installing gas gathering systems and gas plant compression and completing an area 3D seismic program.

Cherhill, Alberta

The Corporation holds a working interest position in 1,985 acres (785 net) of land in the area. There are two producing (0.7 net) natural gas wells producing on these lands at a gross rate of 1,480 mcf/d, with Grey Wolf's share being 889 mcf/d. The gas production from these wells is processed for sweetening, dehydration and compression through both owned and non-owned facilities.

Crossfield, Alberta

In the Crossfield area, Grey Wolf has an interest in 2,400 acres (1,480 net). Grey Wolf operates the three working interest producing gas wells (1.9 net) in the area. Working interests held by Grey Wolf range from 40.9% to 99.3%. In addition, Grey Wolf holds a 1.25% over-riding royalty on a low productivity Viking oil well. Gross natural gas production from the wells averaged 2,470 mcf/d in 2000 and Grey Wolf's share was 1,074 mcf/d. Grey Wolf's share of associated NGLs production was 69 bbls/d.

The property includes a field compressor owned 49.6% by Grey Wolf, which ships natural gas to a third party plant for processing.

Marten Hills, Alberta

In this property, the Corporation owns working interests ranging from 12.5 % to 25.0% in 7,040 gross acres (1,600 net) and six gross wells (1.3 net). The wells consist of four producing (0.75 net) and two non-producing (0.5 net) shallow gas wells. Gross natural gas production from these wells in 2000 was 2,663 mcf/d, with the Corporations working interest share being 564 mcf/d. Currently gas is gathered and processed through a third party-owned facility.

Nestow, Alberta

The Corporation holds a high working interest position in 3,840 acres (3,413 net) of land in the area. The wells include three producing (3.0 net) and two non-producing (0.7 net) wells. Gross and net natural gas production from these wells in 2000 was 2,845 mcf/d. The slightly sour gas produced was wellsite sweetened and transported to third party gas facilities for further processing. During 2000, Grey Wolf successfully re-completed two natural gas wells (2.0 net) and drilled one (1.0 net) unsuccessful well.

Newbrook, Alberta

Grey Wolf held a working interest ranging from 66.5% to 100% in 4,480 gross acres (4,266 net) of land in this area. There were two producing (1.6 net) natural gas wells producing on these lands at a gross rate of 1,275 mcf/d, with Grey Wolf's share being 1,187 mcf/d. This property was sold in November 2000 as part of a property swap transaction.

Pouce Coupe/Valhalla, Alberta

In Pouce Coupe, Grey Wolf holds various interests from 10% to 45% in 12,480 acres (2,896 net) of land in this area. The wells include five producing (1.0 net) and two non-producing (0.5 net) wells. In 2000, the total gross natural gas production was 4,950 mcf/d (769 mcf/d net) with 60 bbls/d (9 bbls/d net) of NGLs. All of the natural gas produced from this property is currently processed through Corporation-owned gathering and processing facilities. Activity in 2000 for Grey Wolf included participation in drilling three wells (0.8 net) that successfully encountered natural gas reserves in the Montney and Gething formations. The Corporation also recompleted five wells (0.5 net) on this property in 2000. Plans for 2001 include conducting a major 2D and 3D seismic program over Grey Wolf interest lands, and drilling two wells (0.4 net) for natural gas potential. Plans are underway to construct a gas gathering pipeline from Pouce Coupe to a Grey Wolf owned facility at nearby Valhalla.

In Valhalla, the Corporation holds a working interest ranging from 3.85% to 25% in 7,520 gross acres (1,253 net) of land in this property. The wells include seven producing (0.3 net) and three non-producing (0.4 net) wells. Gross production from these wells in 2000 was 777 mcf/d, with the Corporation's working interest share being 77 mcf/d. All of the gas produced from this property is currently processed through Corporation-owned gathering and processing facilities. Activity in 2000 for Grey Wolf included participation in the drilling of a natural gas well (0.25 net) late in the year.

Radway, Alberta

The Radway property was comprised of 17,280 gross acres (16,384 net) of land with corporate interests varying from 20% to 100%. This property has 11 producing (10.2 net) and eight non-producing (5.8 net) wells. In 2000, the property's gross natural gas production was 961 mcf/d and the Corporation's working interest production was 899 mcf/d. In 2000, a 100% working interest well was drilled for natural gas that resulted in an abandoned well. Grey Wolf operated this property and owned a 90% interest in a dehydration and compression facility. This property was sold as part of a property swap transaction, effective November 2000.

Redwater, Alberta

Grey Wolf was the operator of the Redwater property where the Corporation held working interests ranging from 50% to 100% in 16,640 gross acres. Redwater had 10 producing (7.5 net) and 10 non-producing (5.5 net) wells. Gross natural gas production from these wells in 2000 was 1,111 mcf/d, with the Corporation's working interest share being 734 mcf/d. The Corporation owned a 50% working interest in two gas processing facilities in the area. During 2000, Grey Wolf participated, at a 50% working interest, in two successful wells. This property was divested as part of a property swap transaction in November 2000.

Thorhild, Alberta

The Thorhild property held 43,680 gross acres of land with the Corporation's interests varying from 2% to 81%. The property included 32 producing (9.3 net) and 13 non-producing (3.8 net) wells. In 2000, Thorhild's gross natural gas production was 3,925 mcf/d and corporate working interest production was 1,149 mcf/d. Grey Wolf owned a 35% interest in a dehydration and compression facility in the area. In 2000, the Corporation participated in three successful recompletions. This property was sold as part of a property swap transaction effective November 2000.

Ladyfern, British Columbia

This property is an exploration area where the Corporation holds an interest in 24,768 acres of gross land (4,126 net). Activity in 2000 for Grey Wolf included participation in two unsuccessful wells (0.3 net). In early 2001, an extensive 3D seismic program has been shot, and will be evaluated to facilitate the identification of potential drilling locations.

Widewater, Alberta

This property is an exploration area where the Corporation holds an interest in 67,958 gross acres of land (29,118 net). Grey Wolf holds an interest in nine (1.9 net) non-producing wells. In 2000, the Corporation participated in drilling two gross (1.0 net) wells for natural gas of which one well (0.5 net) was successful. Development plans for well tie-ins are being evaluated.

Norman Wells, Northwest Territories

This property is an exploration area where the Corporation holds an interest in 465,923 (110,638 net) acres of land that is adjacent to the prolific Norman Wells oil field. There has been no activity on the property over the past year but the Corporation continues to pursue industry partners to conduct a work program on the lands for 2001-2002.

Production by Principal Properties

	2000		1999	
	Natural Gas (mcf/d)	Crude oil and NGLs (bbls/d)	Natural Gas (mcf/d)	Crude oil and NGLs (bbls/d)
Caroline	1,272	62	465	23
Cherhill	889	0	1,543	1
Crossfield	1,074	69	1,455	72
Marten Hills	564	0	577	0
Nestow	2,845	0	1,876	0
Newbrook *	1,187	0	1,333	0
Pouce Coupe/Valhalla	846	9	231	0
Radway *	899	0	1,217	0
Redwater *	734	0	1,538	0
Thorhild *	1,149	0	1,720	0
Other	2,194	57	3,351	80
Total	13,653	197	15,306	176

* Properties disposed of during year 2000.

Wells Drilled

Grey Wolf drilled or participated in the drilling of the following number of wells for the periods indicated:

	Years ended December 31 [1] [2]			
	2000		1999	
	Gross	Net	Gross	Net
Natural Gas	12	4.1	12	3.5
Oil	0	0	0	0.0
Dry & Abandoned	11	4.5	9	3.2
Total	23	8.6	21	6.7
Exploration	11	3.5	4	1.4
Development	12	5.1	17	5.3
Total	23	8.6	21	6.7

Notes:

(1) "Gross" wells means the number of wells in which Grey Wolf has a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Grey Wolf's percentage working interest therein.

Gas Production Facilities

The following table identifies the name and location of the nine largest gas production facilities in which the Corporation has an ownership interest. All of these facilities are located in the province of Alberta. The table indicates gross and working interest natural gas processing capacity as at December 31, 2000:

Area	Operated/ Non-Operated	Facility Type	Ownership Working Interest (%)	Processing Capacity (mmcf/d)	
				Gross	WI
Caroline	Operated	2	64.0	20.0	12.8
Cherhill	Operated	1	100.0	1.9	1.9
Chinchaga	Operated	1	7.5	3.0	0.2
Eaglesham	Non-operated	2	2.5	8.0	0.2
Knopcik (Functional Unit)	Non-operated	2	1.0	71.7	0.7
Millarville	Non-operated	1	2.5	25.0	0.6
Pouce Coupe	Operated	1	10.0	8.0	0.8
Quirk Creek	Non-operated	4	2.6	90.0	2.3
Valhalla	Operated	3	10.0	34.1	3.4
Total				261.7	17.6

Facility Type – Legend	
1	Compression and dehydration
2	Compression, dehydration and refridgeration
3	Compression, dehydration, refridgeration and acid gas processing
4	Compression, dehydration, refridgeration, lean oil absorption and sulphur recovery

Producing and Non-Producing Wells

The following table summarizes, as at December 31, 2000, Grey Wolf's interests in producing and non-producing wells of crude oil or natural gas and NGLs. The stated interests are subject to landowner's and other royalties, where applicable, in addition to usual crown royalties and mineral taxes. All wells are located in the province of Alberta.

	Producing (1)(2)				Non-Producing (1)(2)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Including Unit Wells	41	2	120	24	12	1	78	12
Average Working Interest (%)		5		20		8		16

Notes:

(1) "Gross" wells means the number of wells in which Grey Wolf has an interest.

(2) "Net" wells means the aggregate of the numbers obtained by multiplying each gross well by Grey Wolf's percentage interest therein.

Undeveloped Land Holdings

The following table sets forth Grey Wolf's non-producing land holdings as at December 31, 2000:

	Gross Acres (1)	Net Acres (2)	Value (3)
Alberta	428,251	120,234	6,309
British Columbia	55,179	11,112	1,320
Northwest Territories	465,923	110,638	9,215
Total	949,353	241,984	16,844

Notes:

(1) "Gross Acres" represents the total number of acres in which Grey Wolf has an interest.

(2) "Net Acres" refers to the total of each acreage holding in which Grey Wolf has an interest multiplied by the percentage interest of Grey Wolf therein.

(3) Supplementary Land Services, independent mineral lease evaluation consultants, have valued the Corporation's undeveloped mineral leases effective January 1, 2001.

Petroleum and Natural Gas Reserves

Grey Wolf's interests in its oil and gas properties were evaluated in a report prepared by McDaniel & Associates Consultants Ltd., an independent petroleum consulting firm (the "McDaniel Report"). The McDaniel Report is dated January 19, 2001 and evaluates Grey Wolf's interest in its oil and gas properties effective January 1, 2001.

The following tables summarize the evaluation of the Corporation's reserves:

Petroleum and Natural Gas Reserves Based on Constant Price Assumptions (9)(11)(12)(13)

	Crude Oil (mbbls) (3)		NGLs (mbbls) (4)		Natural Gas (mmcf) (5)	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Proved Reserves (6)						
Proved Producing	42	37	774	503	19,845	14,482
Proved Developed Non-Producing	3	3	287	184	8,989	6,727
Proved Undeveloped	0	0	7	5	251	180
Total Proved Reserves	45	40	1,068	692	29,085	21,389
Probable Reserves (7)	17	13	235	149	8,749	6,447
Proved Plus Probable Reserves	62	53	1,303	841	37,834	27,836

Petroleum and Natural Gas Reserves Based on Escalated Price Assumptions (8)(10)(11)(12)(13)

	Crude Oil (mbbls) (3)		NGLs (mbbls) (4)		Natural Gas (mmcf) (5)	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Proved Reserves (6)						
Proved Producing	41	37	777	507	19,917	14,513
Proved Developed Non-Producing	4	3	287	185	9,008	6,727
Proved Undeveloped	0	0	7	5	256	184
Total Proved Reserves	45	40	1,071	697	29,181	21,424
Probable Reserves (7)	17	13	236	150	9,076	6,484
Proved Plus Probable Reserves	62	53	1,307	847	38,257	27,908

Present Worth of Future Net Production Revenue Based on Constant Price Assumptions (9)(11)(12)(13)

		Discounted at the rate of			
	Undiscounted	10%	12%	15%	20%
			(thousands of dollars)		
Proved Reserves (6)					
Proved Producing	215,932	139,426	130,668	119,656	105,384
Proved Developed Non-Producing	96,913	61,574	57,555	52,481	45,857
Proved Undeveloped	2,056	1,161	1,074	967	834
Total Proved Reserves	314,901	202,161	189,297	173,104	152,075
Probable Reserves (7)	49,894	23,197	20,789	17,937	14,534
Proved Plus Probable Reserves	364,795	225,358	210,086	191,041	166,609

Present Worth of Future Net Production Revenue Based on Escalated Price Assumptions (8)(10)(11)(12)(13)

		Discounted at the rate of			
	Undiscounted	10%	12%	15%	20%
			(thousands of dollars)		
Proved Reserves (6)					
Proved Producing	78,427	53,905	51,064	47,471	42,764
Proved Developed Non-Producing	34,889	22,709	21,355	19,650	17,425
Proved Undeveloped	793	418	384	342	291
Total Proved Reserves	114,109	77,032	72,803	67,463	60,480
Probable Reserves (7)	16,094	7,420	6,664	5,775	4,721
Proved Plus Probable Reserves	130,203	84,452	79,467	73,238	65,201

Notes:

(1) **"Gross Reserves"** means the total of the Corporation's working interests and/or royalty interests share before deducting royalties owned by others.

(2) **"Net Reserves"** means the total of the Corporation's working interests and/or royalty interests share after deducting the amounts attributable to the royalties owned by others.

(3) **"Crude Oil"** means a mixture mainly of pentanes and heavier hydrocarbons produced and sold in the field as crude oil. Minor volumes of field condensate may be included in the crude oil sales in some instances.

(4) **"Natural Gas Liquids" (NGLs)** means a mixture primarily of propane, butane and natural gasoline (pentanes plus) removed from the raw natural gas by processing through an extraction plant. In most instances, a breakdown of these natural gas liquids into propane, butane and natural gasoline has been made. It should be noted, however, that some intermixing of these products occurs in actual field operations and therefore this terminology does not necessarily refer to pure components.

(5) **"Natural Gas"** refers to pipeline natural gas after deducting shrinkage due to processing, fuel and other field losses.

(6) **"Proved Oil and Natural Gas Reserves"** means the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic operating conditions (i.e. prices and costs as of the date the estimate is made). Price includes consideration of changes in existing prices provided by contractual arrangements, as well as escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or a conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or gas-water contacts, if any; and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. The reserve category definitions are equivalent to those of National Policy 2-B.

(7) **"Probable Reserves"** means those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proved at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proved reserves. **Probable reserves present worth values have been reduced by 50% to allow for risk.** The reserve category definitions are equivalent to those of National Policy 2-B.

(8) The McDaniel Report estimates the total capital costs, based on escalating cost assumptions, net to the Corporation, necessary to achieve the estimated future net production to be:

Estimated Capital Costs per Category of Reserves (thousands of dollars)

	Proved Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved	Probable	Proved + Probable
2001	121	1,239	126	1,486	47	1,533
2002		246		246	94	339
2003		175		175	29	204
2004						
2005						
2006						
2007						
2008						
2009						
2010						
2011					2	2
2012						
2013						
2014						
2015						
Remainder					28	28
Total	121	1,660	126	1,907	200	2,106

(9) The constant price case utilizes the product prices received or estimated by the Corporation for December 29, 2000.

Product	Price
Liquids ($/bbl)	
Crude Oil (a)	$39.35
Propane (b)	$57.73
Butane (b)	$48.20
Condensate (b)	$50.09
Gas ($/mmbtu)	
Alberta Average (b)	$10.06
Alberta Spot (c)	$13.45
Transcanada Gas Services Ltd. (b)	$8.89
Pan Alberta Gas Ltd. (b)	$7.91
Progas Ltd. (b)	$7.40
Sulphur ($/Lt) (b)	$7.00

(a) December 29 average posting
(b) December 29 estimate
(c) December 29 actual

The constant price case assumes the continuance of current laws (including ARTC), regulations and operating costs in effect on the date of the McDaniel report. In addition, operating and capital costs have not been increased on an inflationary basis.

(10) The escalating price assumptions assume the continuance of current laws (including ARTC), regulations and any increases in wellhead selling prices, and take into account inflation with respect to future operating and capital costs. In the McDaniel Report, operating and capital costs have been escalated by 2.0% per annum. Product prices in the escalated price evaluation assumes the January 1, 2001 "McDaniel Summary of Price Forecasts". Prices used in the evaluation are adjusted by individual property contractual arrangements. Crude oil and natural gas prices as forecast in the McDaniel Report are as follows:

Future Oil and Gas price Assumptions

	US/Can Exchange Rate ($US/$Can)	WTI Oil ($US/bbl) (1)	Edmonton Light Oil ($/bbl) (2)	Alberta Average Gas ($mmbtu) (3)	Alberta Spot Gas ($/mmbtu)	Progas Gas ($/mmbtu)
2001	0.660	25.00	36.90	6.70	6.90	6.50
2002	0.680	23.00	32.80	5.10	5.20	5.00
2003	0.700	22.40	31.00	4.60	4.60	4.60
2004	0.720	22.30	29.90	4.05	4.05	4.05
2005	0.730	22.70	30.00	3.90	3.90	3.90
2006	0.730	23.20	30.70	3.95	3.95	3.95
2007	0.730	23.70	31.30	4.05	4.05	4.05
2008	0.730	24.20	32.00	4.15	4.15	4.15
2009	0.730	24.70	32.70	4.20	4.20	4.20
2010	0.730	25.20	33.30	4.30	4.30	4.30
2011	0.730	25.70	34.00	4.40	4.40	4.40
2012	0.730	26.20	34.60	4.50	4.50	4.50
2013	0.730	26.70	35.30	4.55	4.55	4.55
2014	0.730	27.20	36.00	4.65	4.65	4.65
2015	0.730	27.70	36.60	4.75	4.75	4.75
2016	0.730	28.30	37.40	4.85	4.85	4.85
2017	0.730	28.90	38.20	4.95	4.95	4.95
2018	0.730	29.50	39.00	5.05	5.05	5.05
2019	0.730	30.10	39.80	5.15	5.15	5.15
2020	0.730	30.70	40.60	5.25	5.25	5.25
Remainder	0.730	30.70	40.60	5.25	5.25	5.25

Notes:
(1) West Texas Intermediate at Cushing Oklahoma
(2) Edmonton price for 40 API, 0.5% sulphur crude
(3) Average Alberta field price applies to the Alberta reference price used in the crown royalty calculations.

(11) The McDaniel Report has included estimates of future abandonment capital costs net to the Corporation, unescalated, of:

Estimated Unescalated Abandonment Costs Per Category of Reserves (thousand of dollars)	
Proved Reserves	
Proved Producing	729
Proved Developed Non-Producing	106
Proved Undeveloped	2
Total Proved Reserves	837
Probable Reserves	23
Proved plus Probable Reserves	860

(12) The extent and character of the Corporation's interest evaluated in the McDaniel Report and all factual data supplied by Grey Wolf to McDaniel & Associates were accepted by McDaniel as represented. The crude oil and natural gas reserve calculations and any projections upon which the McDaniel Report is based were determined in accordance with generally accepted evaluation practices.

(13) The data utilized in the preparation of the McDaniel Report were obtained from the Corporation's files, information on record with the Alberta Energy and Utilities Board, Saskatchewan Energy and Mines, British Columbia Ministry of Energy, Mines & Petroleum Resources and certain non-confidential files of McDaniel. The data provided by the Corporation with respect to ownership interests, sales contracts and current operating costs, were relied upon by McDaniel & Associates as being complete and accurate and were not subject to independent verification by McDaniel & Associates.

Reconciliation of Reserves

The following table provides a summary of the changes in Grey Wolf's working interest share of proven and probable crude oil, NGLs and natural gas reserves, before royalties, which occurred in its most recently completed fiscal year:

Reconciliation of Reserves (before royalties)

	Crude Oil (mbbls)		NGLs (mbbls)		Natural Gas (mmcf)	
	Proven	Probable	Proven	Probable	Proven	Probable
December 31, 1999	39	12	341	27	28,279	7,330
Additions	6	2	329	138	8,881	3,191
Acquisitions	8	0	389	70	8,834	3,367
Dispositions	(1)	0	(1)	0	(9,915)	(4,447)
Revisions	1	3	78	1	(1,901)	(365)
Production	(8)	0	(65)	0	(4,997)	0
December 31, 2000	45	17	1,071	236	29,181	9,076

Capital Expenditures

The following table summarizes Grey Wolf's capital expenditures in thousands of dollars (net of government incentive grants) for the periods indicated:

	Years Ended December 31	
	2000	1999
Land	1,950	4,625
Geological and geophysical	2,098	889
Exploration and development drilling	12,476	4,054
Production equipment and facilities	1,293	864
Exploration and development costs	17,817	10,432
Other corporate assets	124	305
Property acquisitions	10,792	3,662
Property dispositions	(12,674)	(2,629)
Total Capital Expenditures	16,059	11,770

Marketing Arrangements

Grey Wolf's gas marketing strategy is to build a balanced and diversified portfolio in order to minimize price risk associated with any particular market. Approximately 40 percent of Grey Wolf's gas is sold under long-term contracts with Progas Limited, Pan-Alberta Gas Ltd. and TransCanada Pipelines Limited. These companies manage multi-producer supply/sales pools comprising a variety of sales contracts, including spot price sales, in the domestic and United States of America export markets. The remaining 60 percent of the Corporation's gas production is sold in the intra-Alberta spot market. In aggregate, these arrangements result in approximately 70 percent of Grey Wolf's gas production being tied to Alberta spot prices.

Grey Wolf markets its crude oil and natural gas liquids under arrangements with prices tied to Edmonton postings which in turn are based on the price of West Texas Intermediate crude oil. Grey Wolf's reported prices are wellhead prices that reflect quality differences and transportation costs.

Seasonality

The exploration for and development of oil and natural gas reserves is dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

Natural gas is used principally as a heating fuel and for power generation. Accordingly, seasonal variations in weather patterns affect the demand for natural gas. Depending on prevailing conditions, the prices received for sales of natural gas are generally higher in winter than in summer months.

Industry Conditions

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulation imposed by various levels of government. The provincial governments of Alberta and British Columbia have legislation and regulations which govern land tenure, royalties, production rates, environmental protection, the prevention of waste and other matters. Although it is not expected that these controls and

regulation will affect the operations of the Corporation in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. Outlined below are some of the principal aspects of legislation and regulations governing the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing – Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price received by the Corporation depends, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance and other contractual terms. Oil exports from Canada may be made pursuant to export contracts with terms not exceeding 1 year, in the case of light crude, and not exceeding 2 years, in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

Pricing and Marketing - Natural Gas

In Canada, producers of natural gas also negotiate sales contracts directly with the natural gas purchaser. The price of natural gas sold in intra-provincial, inter-provincial and international trade is determined by negotiation between buyers and sellers. The price received by the Corporation depends, in part, on the natural gas heat content, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to a NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity, requires an exporter to obtain an export licence from the NEB, and the issue of such a licence requires the approval of the Governor in Council.

The provincial governments of Alberta and British Columbia also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

Pipeline Capacity

Significant pipeline expansions this past year has removed delivery restrictions on the export pipelines for natural gas and crude oil. Alliance Pipeline commenced natural gas delivery operations in late 2000, exporting 1.5 bcf/d to Chicago, Illinois, U.S.A. Inter-provincial Pipelines has completed the expansion of its crude oil pipeline to Chicago. As well, the AEC operated Express crude oil pipeline to the US Midwest also commenced operations over the past year. Notwithstanding that pipeline expansions are ongoing, the potential lack of firm domestic crude oil and natural gas pipeline capacity may restrict a corporation's ability to market its production.

The North American Free Trade Agreement

On January 1, 1994 the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States of America ("U.S.") and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period), (ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

The NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Land Tenure

The mineral rights to crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years on conditions set forth in provincial legislation, which may include requirements to perform specific work or make mineral lease payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are generally granted by leases on such terms and conditions as may be negotiated.

The Corporation's Exploration Licences in the Northwest Territories are administered by the Federal Government through Indian and Northern Affairs Canada and the National Energy Board. Exploration Licences only grant the right to explore for crude oil and natural gas, and have a term of nine years, consisting of consecutive periods of five and then four years. A Commercial Discovery Licence must be obtained in order to produce oil and natural gas which requires the confirmation of the declaration of a Commercial Discovery and approval of a satisfactory development plan.

Royalties and Incentives

For crude oil, natural gas and associated NGLs production from Crown lands, the royalty regime is a significant factor in the profitability of such production operations. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage

of the value of the gross production. The rate of royalties payable generally depends in part on the type of product being produced, well productivity, geographical location and field discovery date.

From time to time the provincial governments of Alberta and British Columbia have established incentive programs for exploration and development. Such programs often provide for royalty reductions and royalty holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. The trend in recent years has been for provincial governments to allow such programs to expire without renewal, and consequently few such programs are currently operative.

On October 13, 1992, the Government of Alberta implemented major changes to its royalty structure and created incentives for exploring and developing crude oil and natural gas reserves. The incentives created include: (i) a 1 year royalty holiday on new oil discovered on or after October 1, 1992; (ii) incentives by way of royalty holidays and reduced royalties on reactivated, low productivity, vertical re-entry and horizontal wells; (iii) introduction of separate par pricing for light/medium and heavy oil; and (iv) a modification of the royalty formula structure through the implementation of a the Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

In Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price.

In Alberta, certain producers of oil or natural gas are also entitled to a credit against the royalties payable to the Alberta Crown by virtue of the Alberta royalty tax credit program ("ARTC"). The ARTC program is based on a price-sensitive formula, and the ARTC rate varies between a 75% credit, at prices for oil below $100 per cubic meter, and a 25% credit, at prices above $210 per cubic meter. The ARTC rate is applied to a maximum of two million dollars of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from companies claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The ARTC rate is established quarterly based on the average "par price", as determined by the Alberta Resource Development Department for the previous quarterly period. The Government of Alberta is proposing changes to the ARTC program which include (i) the elimination of ARTC for trusts and individuals; (ii) the establishment of a $10,000 minimum royalty payment for ARTC; and (iii) changes to how companies report and verify ARTC eligible properties.

In British Columbia, the amount payable as a royalty in respect of crude oil depends on the vintage of the crude oil (whether it was produced from a pool discovered before or after October 31, 1975), the quantity of crude oil produced in a month and the value of the crude oil. Crude oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price. Natural gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other natural gas may not be less than 15%.

Crude oil and natural gas royalty holidays for specific wells and royalty reduction reduce the amount of Crown royalties paid by the Corporation to the provincial governments. The ARTC provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. These incentives result in increased net income and funds from operations of the Corporation.

Canadian Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of material fines and penalties, the revocation of necessary licenses and authorizations and civil liability for pollution damage.

In Alberta, environmental compliance is governed by the *Alberta Environmental Protection and Enhancement Act* ("AEPEA"). In addition to replacing a variety of older statutes which related to environmental matters, the AEPEA imposes certain new environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes greater penalties for violations.

In British Columbia, energy projects may be subject to review pursuant to the provisions of the *Environmental Assessment Act* ("EAA"). The EAA rolls the previous processes for the review of major energy projects into a single environmental assessment process which contemplates public participation in the environmental review.

The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. The Corporation will be taking such steps as required to ensure compliance with the AEPEA, EAA and similar legislation in other jurisdictions in which it operates. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation also believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

Future Site Restoration

The Corporation has made a provision of $210 thousand for future site restoration in 2000 and has accrued $898 thousand in its financial statements for future site restoration costs. Management does not currently anticipate that material changes to the Corporation's planned capital expenditure program will be required to meet existing environmental standards.

SELECTED FINANCIAL INFORMATION

The following is a summary of selected financial information for the periods indicated in thousands of dollars, except for per share amounts:

	Years ended December 31				
	2000	1999	1998	1997	1996
Total Revenue	$26,009	$15,427	$8,797	$2,448	$739
Net earnings	3,940	1,347	9	556	248
Net earnings per share					
- basic	0.31	0.11	-	0.08	0.04
- fully diluted	0.31	0.11	-	0.08	0.04
Total Assets	64,597	50,541	45,694	21,372	6,068
Total Long-term Debt	11,793	12,066	9,971	2,995	-

Summary of Quarterly Financial Information (unaudited)

	Three Months Ended			
	Dec. 31, 2000	Sept. 30, 2000	June 30, 2000	March 31, 2000
Revenue	$8,504	$6,576	$6,186	$4,743
Net Earnings	2,155	1,252	496	37
Net Earnings per share				
- basic	0.17	0.10	0.04	-
- fully diluted	0.17	0.10	0.04	-

	Three Months Ended			
	Dec. 31, 1999	Sept. 30, 1999	June 30, 1999	March 31, 1999
Revenue	$4,231	$4,110	$3,683	$3,403
Net earnings (loss)	623	523	196	5
Net earnings per share				
- basic	0.05	0.04	0.02	-
- fully diluted	0.05	0.04	0.02	-

Dividend Policy

Grey Wolf has not paid any dividends on its common shares to date and does not expect to pay dividends on such shares in the foreseeable future as it expects to use all available funds to finance future development and growth.

MANAGEMENT'S DISCUSSION AND ANALYSIS

With the benefit of higher commodity prices received throughout the year, Grey Wolf attained record cash flow and earnings levels. Capital expenditures, incurred principally for natural gas exploitation, were funded by internally generated funds and working capital. The Corporation retains its conservative financing strategy, with the ratio of debt to cash flow being reduced to 1.2 years.

Production

Average production in 2000 decreased eight percent to 1,562 BOE/d from 1,707 BOE/d in 1999. Natural gas production declined 10 percent to 13.7 mmcf/d from 15.3 mmcf/d in the previous year. The loss of 2 mmcf/d at Nestow in the fourth quarter of 2000, together with normal reservoir production declines, account for the decrease. Development wells drilled and recompleted in the second half of 2000 were not tied-in and brought on production until early in 2001. Crude oil and NGLs production increased 12 percent to 197 BOE/d in 2000 from 176 BOE/d in 1999 due to the acquisition of increased interests in the Caroline area as a result of the swap transaction completed in November 2000.

Grey Wolf's production remains concentrated on natural gas and NGLs which accounted for 99 percent of total production in 2000. With the exploitation focus maintained on multi-horizon natural gas in western Alberta and northeastern British Columbia, the Corporation will continue to benefit from record high natural gas prices.

Production	2000	1999
Natural gas (mmcf/d)	13,653	15,306
Crude oil and NGLs (bbls/d)	197	176
Oil equivalent (BOE/d)	1,562	1,707

	2000		1999	
Per BOE Analysis	($000s)	($/BOE)	($000s)	($/BOE)
Natural gas ($/mcf)	22,683	4.54	13,481	2.41
Oil and NGL ($/bbl)	2,635	36.55	1,296	20.09
Processing and other	691	1.21	650	1.05
Petroleum and natural gas revenue	26,009	45.49	15,427	24.76
Royalties	(5,897)	(10.32)	(3,755)	(6.03)
Alberta Royalty Tax Credit	517	0.90	1,392	2.23
Operating Costs	(3,462)	(6.05)	(3,236)	(5.19)
Operating netback	17,167	30.02	9,828	15.77
General and administrative costs	(1,384)	(2.42)	(903)	(1.45)
Capital tax	(61)	(0.10)	(110)	(0.18)
Interest expense	(1,126)	(1.97)	(576)	(0.92)
Cash flow from operations	14,596	25.53	8,239	13.22
Depletion and depreciation	(7,924)	(13.86)	(6,663)	(10.69)
Future income taxes	(2,732)	(4.78)	(229)	(0.37)
Net income	3,940	6.89	1,347	2.16

Revenues

Oil and gas revenues in 2000 were up 69 percent to $26.0 million from $15.4 million reported in the previous year. The increase was mainly due to the dramatic increase in commodity prices, offset somewhat by the eight percent decrease in production. The Corporation's average natural gas price in 2000 increased 88 percent to $4.54 per mcf from $2.41 per mcf in 1999. Due to the reduction of pipeline transportation constraints, Canadian natural gas producers benefited from increased prices reflecting

North American market demand. Consistent with world price increases, the average price received for crude oil and NGLs was $36.55 per bbl compared to $20.09 per bbl in 1999, an 82 percent increase.

Revenues for the year also include processing fees of $691 thousand, a slight increase over $650 thousand in 1999.

Revenue

	2000		1999	
($ thousands)		%		%
Natural gas	22,683	88	13,481	87
Oil and NGLs	2,635	10	1,296	8
Processing and other	691	2	650	4
Petroleum and natural gas revenue	26,009	100	15,427	100

Royalties

Royalties increased 57 percent to $5.9 million from $3.8 million in the previous year. Higher natural gas commodity prices resulted in an increase in the gas royalty rate which is highly price sensitive. The Alberta Royalty Tax Credit ("ARTC") was reduced in 2000 to $0.5 million from $1.4 million in 1999. The ARTC is also price sensitive, with higher commodity prices resulting in a lower ARTC rate, which decreased to 25 percent in 2000 from 69 percent in 1999.

Royalties

	2000		1999	
	($000s)	% Rate	($000s)	% Rate
Natural gas	5,166	23	3,423	25
Oil	47	13	41	13
NGLs	684	30	291	29
Gross royalties	5,897	23	3,755	25
Alberta Royalty Tax Credit	(517)	(2)	(1,392)	(9)
Net royalties	5,380	21	2,363	16

Operating Expenses

Operating costs increased slightly to $3.5 million from $3.2 million in 1999 due to increased workover and turnaround costs. On a BOE basis, operating costs for 2000 were $6.05 compared to $5.19 in the prior year. The per BOE increase results primarily to declines in production.

Operating Costs

	2000		1999	
	($000s)	$/BOE	($000s)	$/BOE
Operating	3,462	6.05	3,236	5.19
Costs related to third party processing income	(210)	(0.36)	(252)	(0.40)
Production expenses	3,252	5.69	2,984	4.79

General and Administrative Expenses

General and administrative ("G&A") expenses were up 53 percent to $1.4 million due principally to reorganization charges incurred in the second quarter of 2000. With the added effect of reduced production in 2000, G&A expenses were $2.42 per BOE compared to $1.45 per BOE in 1999.

General and Administrative Expenses

($ thousands)	2000	1999
Gross general and administrative expenses	2,905	2,030
Recoveries	(1,141)	(886)
	1,764	1,144
Capitalized general and administrative expenses	(380)	(241)
Net general and administrative expenses	1,384	903
Net general and administrative expenses per BOE	2.42	1.45

Interest Expenses

Interest expense increased to $1.1 million from $0.6 million in the previous year. This increase was due to a higher debt level resulting from increased capital expenditures in 2000 and an increase in the average interest rate, which rose to an average 7.15 percent during 2000.

Depletion and Depreciation

Total depletion, depreciation and site restoration expense increased to $7.9 million, up 19 percent from the prior year total of $6.7 million. On a BOE basis, depletion and depreciation expense increased to $13.49 from $10.08 in 1999 due to reserve revisions in December 1999 affecting the year 2000 rate. The site restoration provision declined to $210 thousand from $400 thousand due to the divesture of properties with potentially higher site restoration liabilities.

Income Taxes

The provision for future income taxes was $2.7 million, up significantly from the $229 thousand reported in 1999 as net earnings before taxes increased by 299% due to higher commodity prices and to higher non-deductible crown royalties for tax purposes. Capital tax declined slightly to $61 thousand in 2000 from $110 thousand mainly due to a prior year adjustment.

Grey Wolf has approximately $45.3 million of tax pools remaining at December 31, 2000 and accordingly, is not currently cash taxable. Effective the beginning of 2000, the Corporation adopted the new Canadian Institute of Chartered Accountant recommendations for the liability method of tax allocation accounting, which resulted in a $562 thousand reduction in retained earnings.

Estimated Tax Pools at December 31, 2000

($ thousands)	
Canadian oil and gas property expense	21,158
Canadian development expense	9,838
Canadian exploration expense	5,735
Undepreciated capital cost	7,097
Non-capital losses	1,249
Unamortized share issue costs	210
Total	45,287

Cash Flow and Earnings

Cash flow increased 77 percent to $14.6 million ($1.15 per share) in 2000 from $8.2 million ($0.65 per share) in 1999. Net earnings increased 193 percent to $3.9 million ($0.31 per share) in 2000 from $1.3 million ($0.11 per share) in 1999. The increase in both cash flow and net earnings resulted primarily from the higher natural gas and crude oil commodity prices. For purposes of per share calculations, the weighted average shares outstanding for the year amounted to 12.7 million, the same as in 1999.

Cash Flow and Net Earnings ($ thousands, except per share))	2000	1999
Cash flow	14,596	8,239
Cash flow per share	1.15	0.65
Net earnings	3,940	1,347
Net earnings per share	0.31	0.11

Capital Expenditures

During 2000, the Corporation invested a total of $16.1 million in capital expenditures, including property acquisitions net of divestitures, compared to $11.8 million in 1999. The majority of the increase was spent on seismic and drilling in the Corporation's core areas of Caroline and Pouce Coupe. In November 2000, Grey Wolf disposed of properties in Redwater, Thorhild, Radway, Newbrook and Abee in exchange for an increase in the Corporation's interest at Caroline. This property swap transaction also resulted in net proceeds of $1.6 million being paid to Grey Wolf.

Capital Expenditures ($ thousands)	2000	1999
Land	1,950	4,625
Geological and geophysical	2,098	889
Exploration and development drilling	12,476	4,054
Production equipment and facilities	1,293	864
Exploration and development costs	17,817	10,432
Other corporate assets	124	305
Property acquisitions	10,792	3,662
Property dispositions	(12,674)	(2,629)
Total capital expenditures	16,059	11,770

Liquidity and Capital Resources

Capital expenditures of $16.1 million were financed mainly through internally generated funds and working capital. No new shares were issued except for an 1,800 share option exercised by an employee of the Corporation.

Grey Wolf has a bank credit facility of $20.0 million, which bears interest at the bank's prime rate plus one-eighth of one percent. The credit facilities are subject to annual review. At December 31, 2000, the combined bank debt and working capital deficiency amounted to $17.7 million, up 10 percent from the $16.1 million reported one year ago. The year-end debt to current year cash flow multiple was 1.2, which met the Corporation's objective to maintain a cash flow multiple of less than 2.0 times.

Business Risks and Prospects

Grey Wolf's operations are subject to the inherent risks associated with the exploration, development and production of oil and natural gas. These include the uncertainty of finding reserves in economic quantities and the possibility of drilling and production problems.

Grey Wolf seeks to balance risk and reward in its exploration and development projects. The cost of replacing and developing proven and probable reserves is a measure of a company's efficiency in finding new reserves. In making this calculation, Grey Wolf compares all costs associated with exploration, development and production facilities with proven reserves added. Depending on the spending pattern during a specific year, finding and development costs can vary significantly between years.

The Corporation is also subject to market fluctuations in the prices of crude oil and natural gas. Like most industry participants, Grey Wolf has limited ability to affect the price it receives for crude oil and gas production. Historically, the Corporation has chosen not to hedge or forward sell any of its production.

The oil and gas industry is subject to a variety of environmental regulations. Grey Wolf is proactive in ensuring that its activities are carried out in accordance with sound oilfield practices and provincial federal policies and regulations. Grey Wolf has established appropriate emergency procedures intended to mitigate the environmental impact of any accidental occurrences in its field operations. While the Corporation and the industry have a good safety record, the risk of personal injury and property damage cannot be eliminated. Grey Wolf maintains liability and property insurance coverage in amounts sufficient to minimize any financial loss associated with these risks.

Grey Wolf is optimistic about its prospects for continued profitable growth. The Corporation believes it has a highly experienced and dedicated team of professionals with the knowledge and technical tools available to add and exploit oil and natural gas reserves in a manner profitable for its shareholders.

MARKET FOR SECURITIES

The outstanding common shares of Grey Wolf are listed and posted for trading on The Toronto Stock Exchange under the symbol "GWX".

DIRECTORS AND OFFICERS

The Corporation has an audit committee and a compensation committee. Members of each committee are indicated in the table below.

Name and Municipality of Residence	Office	Current Occupation
Donald B. Copeland (1) (2) Calgary, Alberta	Director since May 1996	Independent oil and gas businessman
John F. Curran(1) (2) Calgary, Alberta	Director since May 1996	Senior Partner, Bennett Jones LLP, Barristers and Solicitors
Orval K. Horn Calgary, Alberta	Director since September 1997	Independent oil and gas businessman
James C. Phelps (1) (2) San Antonio, Texas	Director since January 1996	Independent oil and gas consultant
Richard M. Riggs San Antonio, Texas	Director since May 1996	Independent oil and gas consultant
Robert L.G. Watson San Antonio, Texas	Director since May 1996 and Chairman of the Board and Chief Executive Officer	Chairman, President, Chief Executive Officer, Abraxas Petroleum Corporation
James K. Wilson	Senior Vice President & Chief Financial Officer and Corporate Secretary	Senior Vice President & Chief Financial Officer and Corporate Secretary, Grey Wolf Exploration Inc.
Vincent J. Tkachyk	Vice President, Operations	Vice President, Operations, Grey Wolf Exploration Inc.
Francis Cheung	Controller	Controller, Grey Wolf Exploration Inc.

Notes:

(1) Member of the Audit Committee.

(2) Member of the Compensation Committee.

Each of the foregoing individuals has been engaged in his principal occupation or in other capacities with the same firm or organization for the past five years except for: Orval K. Horn, who, prior to January 2001, was President of Jubilee Resources Inc. and prior to September 1997, was President of Pennant Petroleum Ltd.; Vincent J. Tkachyk, who, prior to June 1997, was Vice President of Pennant Petroleum Ltd. and prior to June 1994 was President of Dekalb Energy Company; James K. Wilson, who, prior to March 2000 was Vice President, Finance & CFO and Corporate Secretary of Maxx Petroleum Ltd., and prior thereto, Executive Vice President, Finance & CFO of Chauvco Resources International Ltd. and prior thereto, Senior Vice President, Finance and Administration & CFO of Chauvco Resources Ltd.; and Francis Cheung, who, prior to June, 1998, was with Maxx Petroleum Ltd. as Controller, and prior thereto, was with Riata Resources as Controller.

As of March 13, 2001, all the directors and senior officers of Grey Wolf as a group beneficially owned, directly or indirectly or exercised control or direction over, 923,488 common shares representing 7% of all issued and outstanding common shares of the Corporation. The information contained herein as to securities beneficially owned, directly, or over which control or direction is exercised, is based upon information furnished to Grey Wolf by the respective directors and senior officers.

Each director will hold office until the next annual general meeting of Grey Wolf or until his successor is duly elected, unless his office is earlier vacated in accordance with the by-laws of the Corporation.

FINANCIAL STATEMENTS

AUDITORS' REPORT

To the Shareholders of
Grey Wolf Exploration Inc.

We have audited the balance sheet of Grey Wolf Exploration Inc. as at December 31, 2000 and the statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The financial statements as at and for the year ended December 31, 1999 were audited by another firm of auditors who expressed an unqualified opinion thereon.

Deloitte & Touche LLP

February 23, 2001
Calgary, Canada

Chartered Accountants

BALANCE SHEETS
As at December 31

(thousands of dollars)	2000	1999
ASSETS		
Current		
Accounts receivable *[note 8]*	$9,815	$4,103
Property and equipment *[note 3]*	54,782	46,438
	$64,597	$50,541
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities *[note 8]*	$15,764	$ 8,117
Long-term debt *[note 4]*	11,793	12,066
Future site restoration	898	891
Future taxes *[note 6]*	3,297	3
	31,752	21,077
Shareholders' equity		
Share capital *[note 5]*	27,555	27,552
Retained earnings	5,290	1,912
	32,845	29,464
	$64,597	$50,541

See accompanying notes

On behalf of the Board:

Robert L. Walton James C Phelps

Director Director

STATEMENTS OF EARNINGS AND RETAINED EARNINGS
Years ended December 31

(thousands of dollars, except per share amounts)	2000	1999
Revenue		
Petroleum and natural gas revenue	$26,009	$15,427
Royalties, net of Alberta Royalty Tax Credit	(5,380)	(2,363)
	20,629	13,064
Expenses		
Operating	3,462	3,236
General and administrative	1,384	903
Interest on long-term debt	1,126	576
Depletion, depreciation and site restoration	7,924	6,663
	13,896	11,378
Earnings before taxes	6,733	1,686
Provision for taxes *[note 6]*		
Capital tax	61	110
Future income taxes	2,732	229
Net earnings	3,940	1,347
Retained earnings, beginning of year	1,912	565
Adoption of income tax accounting standard change *[note 6]*	(562)	-
Retained earnings - end of year	$ 5,290	$ 1,912
Basic and fully diluted earnings per share ***[note 7]***	$0.31	$0.11

See accompanying notes

STATEMENTS OF CASH FLOWS
Years ended December 31

(thousands of dollars, except per share amounts)	2000	1999
Operating Activities		
Net earnings	$ 3,940	$ 1,347
Depletion, depreciation and site restoration	7,924	6,663
Future taxes	2,732	229
Cash flow from operations	14,596	8,239
Changes in non-cash working capital	1,936	(289)
	16,532	7,950
Financing Activities		
Increase (decrease) in long-term debt	(273)	2,094
Issue (repurchase) of common shares	3	(78)
	(270)	2,016
Total cash resources provided	16,262	9,966
Investing Activities		
Property and equipment received under property swap agreement	10,779	-
Disposal of property and equipment under property swap agreement	(12,332)	-
Net cash proceeds	(1,553)	-
Other acquisitions	13	3,662
Expenditures for property and equipment	17,941	10,737
Sale of property and equipment	(342)	(2,629)
Site restoration	203	-
	16,262	11,770
Decrease in cash and cash equivalents	-	(1,804)
Cash and cash equivalents, beginning of year	-	1,804
Cash and cash equivalents, end of year	$ -	$ -
Cash flow from operations per share *[note 7]*		
Basic	$1.15	$0.65
Fully diluted	$1.11	$0.62
Cash interest paid	1,123	614
Cash taxes paid	72	104

See accompanying notes

NOTES TO FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

Grey Wolf Exploration Inc. (the "Company") was incorporated under the laws of the Province of Alberta on December 23, 1986. The Company's primary business is the exploration, development and production of crude oil and natural gas in western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles and are expressed in Canadian dollars.

Petroleum and natural gas properties

The Company follows the full cost method of accounting in accordance with the guideline issued by the Canadian Institute of Chartered Accountants whereby all costs associated with the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in a Canadian cost centre and charged to income as set out below. Such costs include acquisition, drilling, geological and geophysical costs related to exploration and development activities. Costs of acquiring and evaluating unproved properties are excluded from the depletion base until it is determined whether or not proved reserves are attributable to the properties or impairment occurs.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion of petroleum and natural gas properties and depreciation of production equipment, except for gas plants and related facilities, is provided on accumulated costs using the unit of production method based on estimated proved petroleum and natural gas reserves, before royalties, as determined by independent engineers. For purposes of the depletion calculation, proven petroleum and natural gas reserves are converted to a common unit of measure on the basis of one barrel of oil or liquids being equal to six thousand cubic feet of natural gas. Depreciation of gas plants and related facilities is calculated on a straight line basis over an average eighteen year term.

The depletion and depreciation cost base includes capitalized costs, less costs of unproved properties, plus provision for future development costs of proved undeveloped reserves.

The net carrying value of the Company's petroleum and natural gas properties is limited to an ultimate recoverable amount. This amount is the aggregate of estimated future net revenues from proved reserves and the costs of unproved properties, net of impairment allowances, less future estimated production costs, general and administration costs, financing costs, site restoration and abandonment costs, and income taxes. Future net revenues are estimated using prices and costs without escalation or discounting, and the income tax and Alberta Royalty Tax Credit legislation in effect at the year end.

Future abandonment and site restoration costs

The estimated cost of future abandonment and site restoration is based on the current cost and the anticipated method and extent of site restoration in accordance with existing legislation and industry practice. The annual charge is provided for on a unit of production basis for all properties except for gas plants for which the annual charge is calculated on a straight-line basis over the estimated remaining life of the plants. Actual site restoration expenditures are charged to the accumulated liability account as incurred.

Other Assets

Furniture, leasehold improvements, computer hardware, software and office equipment are carried at cost and are depreciated over the estimated useful life of the assets at rates varying between 20 percent and 30 percent, on a declining balance basis.

Use of Estimates

The amounts recorded for depletion and depreciation of property and equipment and the provision for abandonment and site restoration are based on estimates. The ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to uncertainty and the effect on the financial statements of changes in such estimates could be significant.

Joint operations

Substantially all of the Company's exploration and development activities are conducted jointly with others, and accordingly the financial statements reflect only the Company's proportionate interest in such activities.

Future income taxes

The Company has adopted, on a retroactive basis without restatement of the 1999 financial statements, the new accounting recommendation of the Canadian Institute of Chartered Accountants "Income Taxes". Under this standard, future income tax assets and liabilities are measured based upon temporary differences between the carrying values of assets and liabilities and their tax basis. Income tax expense (recovery) is computed based on the change during the year in the future tax assets and liabilities. Effects of changes in tax laws and tax rates are recognized when substantially enacted.

Financial instruments

Financial instruments of the Company consist of accounts receivable, accounts payable and accrued liabilities, long-term debt and forward commodity sales contracts. As at December 31, 2000 and 1999, there were no significant differences between the carrying amounts of these financial instruments reported on the balance sheet and their estimated fair values.

The Company also from time to time employs financial instruments to manage its exposure to commodity prices. These instruments are not used for speculative trading purposes.

Gains and losses on commodity price hedges are included in revenues upon the sale of the related production provided there is reasonable assurance that the hedge is and will continue to be effective.

Stock Options

The Company has a stock option plan as described in Note 5. No compensation expense is recognized when the stock options are issued. Consideration received on exercise of stock options is credited to share capital.

3. PROPERTY AND EQUIPMENT

	2000		
	Cost $	Accumulated Depletion and Depreciation $	Net Book Value $
Petroleum and natural gas properties	69,543,143	19,383,519	50,159,624
Gas plants and related production facilities	5,786,479	1,326,197	4,460,282
Other assets	531,147	368,082	163,065
Net property and equipment	75,860,769	21,077,798	54,782,971

	1999		
	Cost $	Accumulated Depletion and Depreciation $	Net Book Value $
Petroleum and natural gas properties	54,879,522	12,370,865	42,508,657
Gas plants and related production facilities	4,494,066	792,833	3,701,233
Other assets	499,942	272,333	227,609
Net property and equipment	59,873,530	13,436,031	46,437,499

Undeveloped property costs of $6,441,705 at December 31, 2000 (1999 – $7,365,579) have been excluded from the depletion base.

4. LONG-TERM DEBT

At December 31, 2000, the Company had a revolving term credit facility with a Canadian chartered bank with a maximum limit of $20,000,000. At December 31, 2000, $11,792,690 was drawn down against this facility (1999 - $12,065,824). Under the facility, loan advances bear interest at bank prime plus 1/8%, or if bankers acceptances are utilized, the current bankers acceptances rate plus 1 1/8%. Loan advances are supported by a first floating charge demand debenture in the amount of $25,000,000 covering all the assets of the Company. Subject to annual renewal, the facility is renewable to May 31, 2002, at which time the outstanding bank debt would convert to a term loan.

5. SHARE CAPITAL

Authorized

Unlimited number of common shares without nominal or par value.

Issued

	#	$
Balance, December 31, 1998	12,704,341	27,630,426
Issuer Bid	(44,600)	(78,056)
Balance, December 31, 1999	12,659,741	27,552,370
Exercise of stock options	1,800	2,880
Balance, December 31, 2000	12,661,541	27,555,250

Stock options

A maximum of 1,270,000 options to purchase common shares have been authorized for issuance under the Company's stock option plan. The options are exercisable on a cumulative basis at 25% per year commencing one year after grant date and expire five years from the date of grant. Options to acquire 1,010,029 common shares are outstanding at December 31, 2000.

	Number Of options	**Weighted average option price**
Balance, December 31, 1998	897,816	3.20
Issued	328,470	1.91
Cancelled	(192,571)	2.83
Balance, December 31, 1999	1,033,715	2.84
Issued	398,376	1.60
Exercised	(1,800)	1.60
Cancelled	(420,262)	2.53
Balance, December 31, 2000	1,010,029	2.30

Options Outstanding				Options Exercisable	
Range of Exercise Prices	Number Outstanding at Dec. 31/00	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercised Price	Number Exercisable at Dec. 31/00	Weighted Average Exercise Price
$1.15 to $2.06	718,626	3.10	$1.73	199,094	$1.95
$3.20 to $3.90	242,373	1.50	$3.51	185,312	$3.71
$4.00 to $4.80	49,030	1.00	$4.65	39,030	$4.80
$1.15 to $4.80	1,010,029	2.58	$2.30	423,436	$2.60

6. PROVISION FOR TAXES

Income taxes recorded on the statement of earnings and retained earnings differ from the tax calculated by applying the combined statutory Canadian corporate and provincial income tax rate as follows:

(dollars)	2000	1999
Calculated income tax expense at 44.62%	3,004,549	752,237
Increase (decrease) in income tax resulting from		
Non-deductible crown royalties and other charges	2,254,168	2,146,809
Resource allowance	(2,066,595)	(1,174,140)
Alberta Royalty Tax Credit	(230,775)	(1,392,117)
Non-deductible depletion and depreciation	-	43,472
Benefit of losses not previously recognized	-	(147,000)
Large corporation tax	61,330	109,686
Other	(229,104)	-
Income tax provision	2,793,573	338,947

The major components of future income tax liability at December 31, 2000 are related to the following accounts:

Property and equipment	$4,767,094
Future site restoration	(400,854)
Share issue costs	(94,059)
Non-capital losses carried forward	(557,361)
ACRI carry-forward	(143,540)
Resource Allowance	(274,036)
Balance, December 31, 2000	$3,297,244

Upon adoption of the new accounting recommendation of the Canadian Institute of Chartered Accountants, the company recorded a future income tax liability of $562 thousand and decreased the Company's retained earnings by $562 thousand. Had the new method not been adopted, net earnings would have been increased by $88 thousand.

As at December 31, 2000, the Company has exploration and development costs, undepreciated capital costs and unamortized share issue costs available for deduction against future taxable income in the following approximate amounts:

(dollars)	
Canadian oil and gas property expense	21,158,000
Canadian development expense	9,838,000
Canadian exploration expense	5,735,000
Undepreciated capital cost	7,097,000
Non-capital losses	1,249,000
Unamortized share issue costs	210,000
	45,287,000

The Company's non-capital losses are available to be carried forward to offset taxable income in future years and expire between 2002 and 2004.

7. PER SHARE AMOUNTS

The calculation of basic net earnings per common share and cash flow from operations per common share is based on the weighted average number of common shares outstanding during the year ended December 31, 2000 of 12,660,528 (1999 – 12,695,313). The effect of any potential common share issuances is anti-dilutive with respect to the earning per share calculation. Fully diluted cash flows from operations was calculated based on 13,238,586 weighted average number of common shares.

Cash flow from operations per share is based on cash flow from operations before changes in non-cash working capital items.

8. RELATED PARTY TRANSACTIONS

Grey Wolf manages the assets and operations of Canadian Abraxas Petroleum Limited ("Canaxas") pursuant to a Management Agreement dated November 12, 1996. Canaxas is a wholly-owned subsidiary of Abraxas Petroleum Corporation ("Abraxas"). Abraxas owns 46.2% of the common shares of Grey Wolf. Canaxas owns 2.7% of the common shares of Grey Wolf.

The aggregate common costs of operations and administration of the Canaxas and Grey Wolf assets are shared on a pro rata basis, based on net revenue.

Amounts due to and from these related parties at December 31, 2000 and 1999 are non-interest bearing, are not collateralized and are due on demand as follows:

(dollars)	2000	1999
Due (to) from Canaxas	3,822,861	(554,254)

Also included in accounts receivable are promissory notes totaling $200,000 which are due from senior officers of the Company. The notes bear interest equal to the Banker's Acceptance rate plus 1 1/8% per annum. Interest is charged at the end of each month against salaries otherwise payable. The notes are fully due and payable by the holders upon termination of employment or resignation.

9. SUBSEQUENT EVENT

On January 19, 2001, the Corporation and Abraxas jointly announced they were in discussions concerning a share-for-share acquisition by Abraxas of the remaining 51% ownership of the Corporation that Abraxas does not currently own.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Grey Wolf's securities and options to purchase securities and interests of insiders in material transactions, where applicable, is contained in Grey Wolf's Management Proxy Circular dated April 6, 2000, which relates to the annual meeting of Shareholders held on May 17, 2000. Additional financial information is contained in the Corporation's comparative financial statements for the years ended December 31, 2000 and 1999.

For copies of the aforementioned documents, please contact:

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